PRESS RELEASE

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CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2017 FOURTH QUARTER AND YEAR END RESULTS

CALGARY, ALBERTA – MARCH 1, 2018 – FOR IMMEDIATE RELEASE

Commenting on the Company's results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "In 2017, Canadian Natural continued to execute on its defined strategy and completed its transition to a long life low decline asset base with the completion and ramp-up of the Horizon Phase 3 expansion. The Company's focus on balanced capital allocation was evident in 2017 as economic resource development, increased balance sheet strength, execution on transformational acquisitions and free cash flow generation combined with our ability to execute with excellence, drove a strong year for the Company."

Canadian Natural's President, Tim McKay, added, "Strong production of Synthetic Crude Oil ("SCO") is targeted from our Oil Sands Mining and Upgrading operations with the midpoint of guidance at 450,000 bbl/d of SCO in the first quarter of 2018. With the completion of Phase 3 at Horizon, production has been strong averaging over 247,000 bbl/d of SCO since December 1, 2017 and operations at our Athabasca Oil Sands Project ("AOSP") continue to perform as expected with integration continuing during the Company's nine months of mine operations. The Company's Oil Sands Mining and Upgrading segment, conventional light oil in Canada and our international assets now make up over 50% of our corporate liquids production mix, a significant increase from approximately 32% in 2016. These products provide significant value to the Company as they are priced in close relation to the high value West Texas Intermediate ("WTI") crude oil commodity price.

Our focus on effective and efficient operations resulted in strong operating costs in 2017. Operating costs were within or on the lower end of corporate guidance ranges. Specifically, Horizon operating costs averaged $21.46/bbl of SCO in 2017, after adjusting for planned downtime, excellent results, with the Company looking to capture additional saving opportunities in 2018.

In 2017, Canadian Natural continued its strong track record of delivering excellent finding and development and acquisition costs and reserve replacement ratios, reflecting the strength of our assets and our ability to execute effectively and efficiently. Our reserve additions in the year were strong with gross proved crude oil, SCO, bitumen and NGL reserves increasing 59% to 7.74 billion barrels and proved natural gas reserves increasing 2% to 6.77 trillion cubic feet. Total proved plus probable BOE reserve life index of the Company is now 33.0 years, with low finding, development and acquisition costs of $12.29/BOE for proved reserves, including the change in future development capital. Additionally, our execution delivered strong reserve replacement ratios of 887% on proved developed producing reserves and 927% on total proved reserves, driven by our low sustaining capital requirement, resulting in significant free cash flow that provides sustainability through any commodity price cycle."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "The financial strength of the Company was displayed in 2017 as we were able to opportunistically acquire accretive assets and bring the Horizon project to completion, making the Company much more robust and sustainable. As a result, annual funds flow and net earnings were significant at approximately $7.3 billion and $2.4 billion respectively, all achieved with an annual average WTI crude oil price under US$51.00/bbl. The resulting free cash flow allowed the Company to increase liquidity to $4.25 billion and reduce debt to annual adjusted EBITDA to 2.7x at year end.

In Q4/17 funds flow reached approximately $2.3 billion, resulting in a Q4/17 ending debt reduction of approximately $460 million, when compared to Q3/17 levels, supporting our near term focus to strengthen our balance sheet. Additionally, as of the April 1, 2018 dividend payment, the Company's Board of Directors has increased our quarterly dividend by 22% to $0.335 per share, reflecting the strength and robustness of our assets and our ability to generate free cash flow. The increase marks the 18th consecutive year of dividend increases, and confirms our commitment to sustainable and increasing returns to shareholders."

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2017**	 Sept 30 2017	 Dec 31 2016	Year Ended **Dec 31 2017**	 Dec 31 2016
Net earnings (loss)	**$ 396**	$ 684	$ 566	**$ 2,397**	$ (204)
Per common share – basic	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.04**	$ (0.19)
– diluted	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.03**	$ (0.19)
Adjusted net earnings (loss) from operations (1)	**$ 565**	$ 229	$ 439	**$ 1,403**	$ (669)
Per common share – basic	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
– diluted	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
Funds flow from operations (2)	**$ 2,307**	$ 1,675	$ 1,677	**$ 7,347**	$ 4,293
Per common share – basic	**$ 1.89**	$ 1.38	$ 1.52	**$ 6.25**	$ 3.90
– diluted	**$ 1.88**	$ 1.37	$ 1.50	**$ 6.21**	$ 3.89
Capital expenditures, excluding AOSP acquisition costs (3)	**$ 1,143**	$ 2,094	$ 411	**$ 4,972**	$ 3,794
Total net capital expenditures (3)	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794
Daily production, before royalties					
Natural gas (MMcf/d)	**1,656**	1,664	1,646	**1,662**	1,691
Crude oil and NGLs (bbl/d)	**744,100**	759,189	585,185	**685,236**	523,873
Equivalent production (BOE/d) (4)	**1,020,094**	1,036,499	859,577	**962,264**	805,782

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Funds flow from operations (formally cash flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

(3) For additional information and details, refer to the net capital expenditures table in the Company's MD&A.

(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

Annual Highlights

- Net earnings of $2,397 million were realized in 2017, resulting in adjusted net earnings of $1,403 million, representing an increase of $2,072 million in adjusted net earnings compared to 2016 levels.
- Funds flow generation increased significantly in 2017 with annual funds flow from operations of $7,347 million, an increase of 71% or $3,054 million compared to 2016 levels of $4,293 million.
- Record annual production volumes of 962,264 BOE/d were achieved in 2017, representing an increase of 19% from 2016 levels. The increase was a result of the Company's liquids segment, with annual crude oil and NGL production volumes reaching 685,236 bbl/d, an increase of 31% from 2016 levels.
- Canadian Natural's balance of products has improved significantly with current production mix on a BOE/d basis of 50% light crude oil blends, 25% heavy crude oil blends and 25% natural gas, based upon the mid-point of annual 2018 production guidance, a significant change from 2016 when our production mix was approximately 32% light crude oil blends, 33% heavy crude oil blends and 35% natural gas.
- In 2017, the Company achieved annual natural gas production volumes of 1,662 MMcf/d, consistent with 2016 levels. Natural gas volumes were maintained as the Company made strategic, return based capital allocation decisions to maintain the Company's natural gas business.

- Canadian Natural is committed to reducing its environmental footprint by leveraging technology, adopting innovation and maintaining effective and efficient operations. The Company has made significant gains in our environmental performance:
  - Canadian Natural's greenhouse gas ("GHG") emissions intensity decreased 16% from 2012 to 2016. Additionally methane emissions from our Alberta heavy crude oil operations decreased 71% over the same period.
  - The Company has developed a pathway utilizing technology advancements to reduce its oil sands GHG emissions intensity to be equivalent with light crude oil in North America.
  - Over 1.5 million tonnes of annual CO2 capture and sequestration capacity at the Company's Oil Sands Mining and Upgrading operations.
  - When the North West Redwater Refinery is fully on-stream, Canadian Natural targets to capture and sequester 2.7 million tonnes of CO2 annually, the 4th largest of all industries globally.
  - The Company has a strong commitment to effective and efficient water management with over 90% of water used in our Oil Sands Mining and Upgrading operations being recycled water.
  - Canadian Natural has invested over $500 million in Research and Development in each of the last two years. In 2016 Canadian Natural was the 4th largest Research and Development investor of all industries in Canada.
- Environmental and safety performance are key metrics in our compensation program, along with key operational metrics and financial metrics such as total shareholder return, return on capital, return on equity and debt metrics such as debt to EBITDA and debt to book capitalization.
- At the Company's world class Oil Sands Mining and Upgrading assets, the Athabasca Oil Sands Project ("AOSP") and Horizon Oil Sands ("Horizon"), operations were strong in 2017, with annual and Q4/17 production reaching 282,026 bbl/d and 321,496 bbl/d respectively, of Synthetic Crude Oil ("SCO").
  - During 2017, at Horizon, the Company successfully completed the Phase 3 expansion, the final component of the Company's transition to a long life low decline asset base. The completion of the Horizon Phase 3 expansion has increased the output of fully upgraded 34 degree API light sweet SCO, with December production averaging 247,226 bbl/d of SCO. The resulting impact to operating costs was significant, with December operating costs below $20.00/bbl of SCO.
    - Horizon achieved record annual production of 170,089 bbl/d of SCO in 2017, a 38% increase over 2016 levels, as a result of a full year of Phase 2B production and the completion and tie-in of the Horizon Phase 3 expansion.
    - Operational performance has been strong after the ramp-up of the Horizon Phase 3 expansion as production averaged over 247,000 bbl/d of SCO since December 1, 2017.
    - Through safe, steady and reliable operations and a strong focus on continuous improvement, after adjusting for planned downtime in 2017, the Company realized record low annual average operating costs of $21.46/bbl of SCO at Horizon, a 15% reduction from 2016 levels. Including turnaround time, operating costs were $24.98/bbl of SCO, a 13% reduction from 2016 levels.
    - In 2017, Horizon project capital expenditures totaled $821 million, $89 million below the Company's 2017 corporate guidance.
  - At the AOSP, the Company operated the Albian mines for 7 months in 2017 and achieved strong reliability and utilization. As a result, the Company added 111,937 bbl/d and 180,221 bbl/d of AOSP SCO in 2017 and Q4/17 respectively, net to Canadian Natural, both above the midpoint of previously issued guidance. A combination of strong production and modest integration gains resulted in operating costs of $26.34/bbl for upgraded products, below the Company's 2017 operating cost guidance of $27.00/bbl to $31.00/bbl.
- The transition to a long life low decline asset base is complete following the Horizon Phase 3 expansion. Canadian Natural’s production is resilient as long life low decline assets make up approximately 73% of 2018 liquids production guidance, including AOSP, Horizon, Pelican Lake and Thermal in situ oil sands assets.
- The Company’s 2017 drilling program consisted of 523 net wells, excluding strat/service wells, a 333 net well increase over its 2016 drilling program. The Company continues to be prudent with its capital allocation in a volatile commodity price environment, maintaining significant capital flexibility in its 2018 budget that is targeting 608 net producing wells over the year.

- Thermal in situ oil sands (“thermal in situ”) annual production volumes reached 120,140 bbl/d, at the top end of 2017 guidance, representing an 8% increase from 2016 levels.
  - At Primrose, production was strong in 2017 with volumes reaching 81,501 bbl/d, an increase of 11% from 2016 levels. Operating costs in 2017 were $12.33/bbl, including energy costs, slightly below 2016 costs.
  - At Kirby South the Company's Steam Assisted Gravity Drainage (“SAGD”) project, annual production volumes of 36,107 bbl/d were achieved, a 4% decrease from 2016 levels, as the Company successfully completed planned turnaround activities in the year.
    - Including energy costs, Kirby South achieved annual operating costs of $9.50/bbl, in-line with 2016 levels.
- Pelican Lake operations were strong with annual production of 51,743 bbl/d, an increase of 9% from 2016 levels. The increase was a result of the Company's successful integration of the acquired assets in Q4/17 and a modest drilling program. The acquired assets are now fully integrated and the Company has begun to re-initiate polymer flood conversions across portions of the acquired lands. The conversions will continue throughout 2018 adding to Canadian Natural's long life low decline asset mix.
  - Record low annual operating costs of $6.42/bbl were achieved in 2017, a 3% reduction from 2016 levels.
- Primary heavy crude oil production decreased as expected to 95,530 bbl/d in 2017, following the Company's proactive decision to reduce its primary heavy crude oil drilling program from peak levels in 2014. Canadian Natural is an industry leading primary heavy crude oil producer and continues to focus on optimization of its assets.
  - Operating costs of $15.71/bbl were realized in 2017 in primary heavy crude oil.
- North America light crude oil and NGL production increased 5% to 92,036 bbl/d in 2017 from 2016 levels, due to a modest drilling program and minor property acquisitions. As a result, the Company's conventional light crude oil and NGL production was approximately equivalent to the Company's primary heavy crude oil production.
  - Operating costs of $14.30/bbl were realized in 2017 in North America light crude oil and NGL.
- North America natural gas production was 1,601 MMcf/d in 2017, in-line with 2016 levels, after continued impacts of poor reliability at a third party facility and the strategic decision to maintain natural gas production.
  - Operating costs in North America natural gas were within guidance at $1.19/Mcf in 2017.
- International Exploration & Production (“E&P”) annual production volumes were within production guidance and averaged 43,761 bbl/d.
  - North Sea volumes of 23,426 bbl/d were realized in 2017, consistent with 2016 levels, due to a modest drilling program in the year partially offsetting declines. Additionally, the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea resulted in annual operating costs decreasing by 14% to $36.60/bbl, from 2016 levels.
  - Offshore Africa’s production decreased by 22%, as expected to 20,335 bbl/d from 2016 levels, due to normal declines and planned turnarounds in 2017. Operating costs in Côte d'Ivoire were strong in 2017 at $12.41/bbl, within corporate guidance.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2017, the Company had $4.25 billion of available liquidity, including cash and cash equivalents, an increase of $1.21 billion from December 31, 2016. Year end 2017 debt to book capitalization was 41% and debt to adjusted EBITDA strengthened to 2.7x.
- The Company remained focused on returns to shareholders in 2017 increasing dividends by approximately 17% to $1.10 per share. Subsequent to year end the Company increased its quarterly dividend by 22% to $0.335 per share payable on April 1, 2018. The increase marks the 18th consecutive year that Canadian Natural has increased its dividend, reflecting the Board of Director's confidence in the Company's sustainability and robustness of the asset base driving its ability to generate significant funds flow.
- Effective March 1, 2018, the Company promoted Tim McKay to President and Mr. McKay has been appointed to the Company's Board of Directors. Additionally, Steve Laut has assumed the role of Executive Vice-Chairman. The Company takes a very proactive and disciplined approach to succession, with well-planned and very successful transitions, ensuring we maintain our strong corporate culture and top tier performance.

2017 Reserves Update

- Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs as at December 31, 2017 (all reserve values are Company Gross unless stated otherwise).
  - Proved crude oil, SCO, bitumen and NGL reserves increased 59% to 7.74 billion barrels. Proved natural gas reserves increased 2% to 6.77 Tcf. Total proved reserves increased 49% to 8.87 billion BOE. The increase is largely driven by the Company's acquisition of AOSP.
  - Proved developed producing reserve additions and revisions are 3.024 billion barrels of crude oil, SCO, bitumen and NGL and 536 billion cubic feet of natural gas. The total proved developed producing reserves replacement ratio is 887%.
  - Proved reserve additions and revisions are 3.126 billion barrels of crude oil, SCO, bitumen and NGL and 761 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio is 927%. The total proved BOE reserve life index is 24.6 years.
  - Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 34% to 10.26 billion barrels. Proved plus probable natural gas reserves increased 6% to 9.62 Tcf. Total proved plus probable reserves increased 29% to 11.87 billion BOE.
  - Proved plus probable reserve additions and revisions are 2.846 billion barrels of crude oil, bitumen, SCO and NGL and 1.15 trillion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio is 866%. The total proved plus probable BOE reserve life index is 33.0 years.
  - Proved finding, development and acquisition (FD&A) cost, excluding changes in future development capital (FDC), is strong at $5.15/BOE. Proved plus probable FD&A is $5.52/BOE.
  - Proved net present value of future net revenues, before income tax, discounted at 10%, is $89.8 billion, a 30% increase from the year end 2016 evaluation. Proved plus probable net present value is $114.5 billion, a 24% increase from year end 2016.

Fourth Quarter Highlights

- Net earnings of $396 million and adjusted net earnings of $565 million were realized in Q4/17. Canadian Natural generated significant funds flow from operations of $2,307 million in Q4/17, increases of $632 million and $630 million over Q3/17 and Q4/16 levels, respectively.
- The Company's corporate production volumes averaged a record 1,020,094 BOE/d in Q4/17, in-line with Q3/17 levels and a 19% increase from Q4/16 levels.
- Canadian Natural's corporate crude oil and NGL production volumes averaged 744,100 bbl/d, a decrease of 2% from Q3/17 due to Horizon planned downtime for turnaround and tie-in activities. Crude oil and NGL production volumes increased from Q4/16 by 27% primarily as a result of high reliability and strong production from the Horizon Phase 2B and Phase 3 expansions and a full quarter of production from the AOSP.
- At the Company's world class Oil Sands Mining and Upgrading assets, the AOSP and Horizon, operations were strong in Q4/17 with quarterly production reaching 321,496 bbl/d of SCO.
  - At Horizon, the Phase 3 expansion was completed in Q4/17, marking the completion of the Company's transition to a long life low decline asset base.
    - Q4/17 production of 141,275 bbl/d of SCO was realized as the Company completed turnaround and tie-in activities for the Horizon Phase 3 expansion. As a result of the majority of the planned downtime coming in Q4/17, production in the quarter decreased from Q3/17 levels by 10%. The ramp-up of the Phase 3 expansion performed better than originally targeted, with December 2017 production averaging approximately 247,226 bbl/d of SCO, approximately 7,200 bbl/d of SCO greater than originally targeted.
    - Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized average unadjusted operating costs of $32.29/bbl in Q4/17, a strong result given 33 days of planned downtime in the quarter as part of the 52 day turnaround and tie-in related to the Phase 3 expansion. After normalizing for planned downtime, quarterly operating costs were strong at $21.13/bbl of SCO in Q4/17.

  - At the AOSP in Q4/17, the Company's second full quarter of operations, production was 180,221 bbl/d of AOSP SCO, net to Canadian Natural, strong results given planned pitstops at the Jackpine and Muskeg River mines in the quarter. Including the impact of planned pit stops, operating costs of $27.95/bbl were achieved, an increase of 14% from Q3/17 levels.
- Thermal in situ operations were strong in Q4/17, with production averaging 124,121 bbl/d, in-line with Q3/17 and a 4% decrease from Q4/16 levels.
  - Primrose production was strong in Q4/17 averaging 84,834 bbl/d, an increase of 5% from Q3/17. Including energy costs, operating costs of $11.16/bbl were achieved in the quarter.
  - Kirby South, the Company's SAGD project achieved production of 35,320 bbl/d in Q4/17.
    - Including energy costs, strong operating costs of $9.74/bbl were achieved in the quarter. Kirby South's Steam to Oil Ratio ("SOR") was 2.9 in Q4/17, as the Company began steam circulation of new well pairs drilled in Q4/17. Normalized to exclude wells in circulation, the SOR was 2.7 in Q4/17.
- Pelican Lake heavy crude oil production of 65,654 bbl/d in Q4/17 increased by 38% from both Q3/17 and Q4/16 levels, as a result of a full quarter of production of the fully integrated, recently acquired assets. Operations continued to be optimized in the quarter, resulting in favorable operating costs of $6.81/bbl in Q4/17, increases of 14% and 4% from Q3/17 and Q4/16 levels respectively, due to the integration of acquired assets.
- Primary heavy crude oil production averaged 99,326 bbl/d in Q4/17, in-line with Q3/17, as a result of the Company's successful drilling program.
- North America light crude oil and NGL quarterly production averaged 94,437 bbl/d, representing 2% and 8% increases from Q3/17 and Q4/16 levels respectively, as a result of a successful drilling program.
- The Company's North America natural gas production in Q4/17 averaged 1,596 MMcf/d, in-line with Q3/17 and Q4/16 levels.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK section of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, facilitating improved value for the Company's shareholders.

Underpinning this asset base is long life low decline production from Horizon mining and upgrading and the AOSP mining and upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of low decline, low reserve replacement costs, and effective and efficient operations means these assets provide substantial and sustainable cash flow throughout the commodity price cycle.

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within its conventional asset base. These projects can be executed quickly and with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs which can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control a major component of its operating cost and minimize production commitments. Low capital exposure projects can be quickly stopped or started depending upon success, market conditions, or corporate needs.

Canadian Natural's balanced portfolio, built with both long life low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

	Year Ended Dec 31			
	2017		2016	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**529**	**495**	188	174
Natural gas	**27**	**21**	11	9
Dry	**7**	**7**	7	7
Subtotal	**563**	**523**	206	190
Stratigraphic test / service wells	**289**	**289**	268	268
Total	**852**	**812**	474	458
Success rate (excluding stratigraphic test / service wells)		**99%**		96%

- The Company's total crude oil and natural gas drilling program was 523 net wells for the year ended December 31, 2017, excluding strat/service wells, an increase of 333 net wells from the same period in 2016. The change in drilling reflects the flexibility of Canadian Natural's resource development program and the Company's disciplined capital allocation process.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs production (bbl/d)	**259,416**	238,844	232,019	**239,309**	239,912
Net wells targeting crude oil	**123**	145	75	**472**	170
Net successful wells drilled	**120**	144	72	**466**	163
Success rate	**98%**	99%	96%	**99%**	96%

- Annual production volumes of North America crude oil and NGLs averaged 239,309 bbl/d in 2017, in-line with 2016 levels and within the Company's annual production guidance.
- Pelican Lake operations were strong with annual production of 51,743 bbl/d, an increase of 9% from 2016 levels. The increase was as a result of the Company's successful integration of the acquired assets in Q4/17 and a modest drilling program. The acquired assets are now fully integrated and the Company has begun to re-initiate polymer flood conversions across portions of the acquired lands. The conversions will continue throughout 2018 adding to Canadian Natural's long life low decline asset mix.
  - Record low annual operating costs of $6.42/bbl were achieved in 2017, a 3% reduction from 2016 levels.
  - Overall 56% of the Pelican Lake pool is under polymer flood on an area basis. Canadian Natural is targeting to ultimately convert approximately 70% of the pool to polymer flood.
- Primary heavy crude oil production decreased as expected to 95,530 bbl/d in 2017, following the Company's proactive decision to reduce its primary heavy crude oil drilling program from peak levels in 2014. Canadian Natural is the industry leading primary heavy crude oil producer and continues to focus on optimization of the assets.
  - Operating costs of $15.71/bbl were realized in 2017.
  - Drilling continued in primary heavy crude oil in 2017 with 415 net wells drilled, an increase of 255 wells from 2016 levels.
- North America light crude oil and NGL production increased 5% to 92,036 bbl/d in 2017 from 2016 levels, due to a modest drilling program and minor property acquisitions. As a result, our conventional light crude oil and NGL production was approximately equivalent to the Company's primary heavy crude oil production.
  - Operating costs of $14.30/bbl were realized in 2017.
- The Company’s 2018 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 253,000 bbl/d - 263,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Bitumen production (bbl/d)	**124,121**	122,372	129,329	**120,140**	111,046
Net wells targeting bitumen	**5**	10	8	**27**	9
Net successful wells drilled	**5**	10	8	**27**	9
Success rate	**100%**	100%	100%	**100%**	100%

- Thermal in situ annual production volumes reached 120,140 bbl/d, at the top end of 2017 guidance, representing an 8% increase from 2016 levels.
  - At Primrose, production was strong in 2017 with volumes reaching 81,501 bbl/d, an increase of 11% from 2016 levels. Operating costs were maintained in the year at $12.33/bbl, including energy costs, slightly below 2016 costs.
    - Additionally, strong results from the Company's low pressure steamflood continue at Primrose. The 2017 annual production under steamflood averaged 39,300 bbl/d, an increase from 2016 average levels of approximately 10,900 bbl/d.
  - At Kirby South, the Company's SAGD project, the Company achieved annual production volumes of 36,107 bbl/d, a 4% decrease from 2016 levels, as a result of planned turnaround activities in the year.
    - Including energy costs, Kirby South achieved annual operating costs of $9.50/bbl, in-line with 2016 levels. Annual SOR at Kirby South was 2.8 in 2017.
  - Kirby North, the Company's targeted 40,000 bbl/d SAGD project with targeted first oil in Q1/20 continues to be trending slightly ahead of schedule and cost performance is trending on budget. Civil works and tank contracts at the plant site have been completed with building and equipment modules set at the plant site. The construction and drilling workforce is currently at 740 people, including satellite module yards.

- The Company’s 2018 thermal in situ annual production guidance remains unchanged and is targeted to range between 107,000 bbl/d - 127,000 bbl/d.

Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Natural gas production (MMcf/d)	**1,596**	1,593	1,578	**1,601**	1,622
Net wells targeting natural gas	**2**	3	4	**22**	9
Net successful wells drilled	**2**	3	4	**21**	9
Success rate	**100%**	100%	100%	**95%**	100%

- North America natural gas production was 1,601 MMcf/d in 2017, in-line with 2016 levels, after continued impacts of poor reliability at a third party facility and the strategic decision to maintain natural gas production.
  - Operating costs in North America natural gas were within guidance at $1.19/Mcf in 2017.
  - Production in Q4/17 was below corporate guidance primarily due to a proactive decision to shut-in production volumes of approximately 24 MMcf/d related to low natural gas prices and 39 MMcf/d related to the impact of reliability issues at a third party facility.
  - The Company uses approximately 32% of its total equivalent gas production internally in its operations providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 29% of the natural gas production is exported to other North American markets or sold internationally, with the remaining 39% of the Company's production being exposed to AECO/Station 2 pricing.
- The Company’s 2018 total natural gas annual production guidance remains unchanged and is targeted to range from 1,650 MMcf/d - 1,710 MMcf/d.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil production (bbl/d)					
North Sea	**19,548**	24,832	24,085	**23,426**	23,554
Offshore Africa	**19,519**	18,776	21,689	**20,335**	26,096
Natural gas production (MMcf/d)					
North Sea	**37**	46	44	**39**	38
Offshore Africa	**23**	25	24	**22**	31
Net wells targeting crude oil	**—**	—	0.9	**1.8**	2.1
Net successful wells drilled	**—**	—	0.9	**1.8**	2.1
Success rate	**—**	—	100%	**100%**	100%

- International E&P annual production volumes were within production guidance and reached 43,761 bbl/d.
  - North Sea volumes of 23,426 bbl/d were realized in 2017, consistent with 2016 levels, due to a modest drilling program in the year helping to offset declines. Additionally, the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea resulted in annual operating costs decreasing by 14% to $36.60/bbl, from 2016 levels.
    - In 2018, the Company is targeting to drill 4.6 net producing wells and 0.9 net injector wells in the North Sea, scheduled to commence in Q1/18. The program targets to add average net production of approximately 3,000 bbl/d in Q4/18.
  - Offshore Africa's production decreased by 22%, as expected to 20,335 bbl/d from 2016 levels, after a successful infill drilling program in early 2016 and no drilling in 2017. Operating costs in Côte d'Ivoire were strong in 2017 at $12.41/bbl, within corporate guidance.
    - In 2018, the Company is targeting to drill 1.7 net producing wells and 1.2 net injector wells at Baobab which are scheduled to commence in Q2/18. The program targets to add average net production of approximately 5,700 bbl/d in Q4/18.
- The Company's 2018 International annual production guidance remains unchanged and is targeted to range from 40,000 bbl/d - 45,000 bbl/d.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Synthetic crude oil production (bbl/d) (1)	**141,275**	156,465	178,063	**170,089**	123,265

(1) Q4/17 SCO production before royalties excludes 1,730 bbl/d of SCO consumed internally as diesel (Q3/17 – 0 bbl/d; Q4/16 – 1,619 bbl/d; year ended December 31, 2017 – 651 bbl/d; year ended December 31, 2016 – 1,966 bbl/d).

- During 2017 at Horizon, the Company successfully completed the Phase 3 expansion, the final component of the Company's transition to a long life low decline asset base. The completion of the Horizon Phase 3 expansion has increased the output of fully upgraded 34 degree API light sweet SCO, with December production averaging 247,226 bbl/d of SCO. The resulting impact to operating costs was significant, with December operating costs below $20.00/bbl of SCO.
  - Horizon achieved record annual production of 170,089 bbl/d of SCO in 2017, a 38% increase over 2016 levels, as a result of a full year of Phase 2B production and the completion and tie-in of the Horizon Phase 3 expansion.
  - Operational performance has been strong after the ramp-up of the Horizon Phase 3 expansion as production has averaged over 247,000 bbl/d of SCO since December 1, 2017.
  - Through safe, steady and reliable operations and a strong focus on continuous improvement, after adjusting for planned downtime in 2017, the Company realized record low annual average operating costs of $21.46/bbl of SCO at Horizon, a 15% reduction from 2016 levels. Including planned downtime, operating costs were $24.98/bbl of SCO, a 13% reduction from 2016 levels.
  - In 2017, Horizon project capital expenditures totaled $821 million, $89 million below the Company's 2017 corporate guidance.
  - The engineering and design work is proceeding as planned on the potential Paraffinic and VGO expansions at Horizon and will continue throughout 2018.
  - Ongoing work is proceeding to define if incremental capacity is attainable at Horizon and is targeted to be identified in Q2/18.
- Directive 85 (formerly Directive 74) implementation at Horizon remains on track and was 74% physically complete as at December 31, 2017. This project includes research into tailings management and investments in technological advancements for the cessation of the use of traditional tailings ponds.

North America Oil Sands Mining and Upgrading – AOSP

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Synthetic crude oil production (bbl/d) (1)	**180,221**	197,900	—	**111,937**	—

(1) Consists of heavy and light synthetic crude oil products.

- At the AOSP, the Company operated the Albian mines for 7 months in 2017 and strong reliability and utilization were achieved. As a result the Company added 111,937 bbl/d of AOSP SCO, net to Canadian Natural in 2017, above the midpoint of previously issued guidance. A combination of strong production and modest integration gains resulted in operating costs of $26.34/bbl for upgraded products, below the Company's 2017 operating cost guidance of $27.00/bbl to $31.00/bbl.
  - In early Q4/17, Canadian Natural successfully completed planned pit stops at both the Jackpine and Muskeg River mines.
  - The Company will continue to operate in the most effective and efficient manner and will continue to be diligent in order to identify additional synergies.
- The Company's 2018 Oil Sands Mining and Upgrading annual production guidance remains unchanged and is targeted to range from 415,000 bbl/d - 450,000 bbl/d of upgraded products.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 55.39**	$ 48.19	$ 49.33	**$ 50.93**	$ 43.37
WCS blend differential from WTI (%) (2)	**22%**	21%	30%	**23%**	32%
SCO price (US$/bbl)	**$ 58.64**	$ 48.83	$ 48.91	**$ 52.20**	$ 43.94
Condensate benchmark pricing (US$/bbl)	**$ 57.96**	$ 47.96	$ 48.37	**$ 51.65**	$ 42.51
Average realized pricing before risk management (C$/bbl) (3)	**$ 53.42**	$ 46.33	$ 45.00	**$ 48.57**	$ 36.93
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.85**	$ 1.94	$ 2.67	**$ 2.30**	$ 1.98
Average realized pricing before risk management (C$/Mcf)	**$ 2.55**	$ 2.29	$ 3.14	**$ 2.76**	$ 2.32

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

- WTI averaged US$50.93/bbl in 2017, an increase of 17% from US$43.37/bbl in 2016. WTI averaged US$55.39/bbl for Q4/17, an increase of 12% from US$49.33/bbl in Q4/16, and an increase of 15% from US$48.19/bbl for Q3/17. WTI pricing for Q4/17 and annual 2017 has increased from the comparable periods due to declines in global crude oil inventories as a result of OPEC's adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil. Going forward, the Company expects WTI pricing to continue to reflect volatility in supply and demand factors and geopolitical events.
- The WCS Heavy Differential averaged US$11.97/bbl in 2017 from US$13.91/bbl in 2016, representing a 14% decrease. The WCS Heavy Differential averaged US$12.28/bbl for Q4/17 , a decrease of 16% from US$14.59/bbl for Q4/16 , and an increase of 24% from US$9.94/bbl for Q3/17. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. Subsequent to quarter end, the WCS Heavy Differential widened due to third party pipeline outages and timing of access to rail for industry to move the incremental barrels.

- Canadian Natural contributed approximately 190,000 bbl/d of its heavy crude oil stream to the WCS blend in Q4/17. The Company remains the largest contributor to the WCS blend, accounting for 48% of the total blend.
- The SCO price averaged US$52.20/bbl in 2017, an increase of 19% from US$43.94/bbl in 2016. The SCO price averaged US$58.64/bbl for Q4/17, an increase of 20% from US$48.91/bbl in Q4/16, and an increase of 20% from US$48.83/bbl for Q3/17. The increase in SCO pricing for Q4/17 and 2017 from the comparable periods was primarily due to changes in WTI benchmark.
- AECO natural gas prices averaged $2.30/GJ in 2017 from $1.98/GJ in 2016, representing an increase of 16%. AECO natural gas prices averaged $1.85/GJ for Q4/17, a decrease of 31% from $2.67/GJ in Q4/16, and a decrease of 5% from $1.94/GJ in Q3/17. The increase in natural gas prices in 2017 compared with 2016 primarily reflected the rebalancing of natural gas storage inventory to historically normal levels. The decrease in AECO natural gas prices in Q4/17 compared with Q4/16 and Q3/17 continued to reflect third party pipeline constraints limiting flow of natural gas to discretionary storage and export markets as well as increased natural gas production in the basin.
- The North West Redwater refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta and create demand for 79,000 bbl/d of dilbit that will not require export pipelines, which will help reduce pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. For project updates, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.
    - The North West Redwater refinery began processing light crude oil late in November 2017, and continues to progress with its planned ramp-up schedule.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's funds flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production levels of 1,020,094 BOE/d in Q4/17, with approximately 98% of total production located in G7 countries.
    - Canadian Natural's balance of products has improved significantly with current product mix on a BOE/d basis of 50% light crude oil blends, 25% heavy crude oil blends and 25% natural gas, based upon the mid-point of annual 2018 production guidance, a significant change from 2016 when our product mix was approximately 32% light crude oil blends, 33% heavy crude oil blends and 35% natural gas.
    - The transition to a long life low decline asset base is complete following the Horizon Phase 3 expansion. Canadian Natural's production is resilient as long life low decline assets makes up approximately 73% of 2018 liquids production guidance, when including the AOSP, Horizon, Pelican Lake and Thermal in situ oil sands assets.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2017, the Company had $4.25 billion of available liquidity, including cash and cash equivalents, an increase of $1.21 billion from December 31, 2016.
    - Important metrics improved in Q4/17, with debt to book capitalization at 41% and debt to adjusted EBITDA strengthening to 2.7x, as at December 31, 2017.
- Balance sheet strength continues to be a focus of the Company and strong financial performance in the quarter resulted in a Q4/17 ending debt reducing approximately $460 million from Q3/17 levels, while liquidity increased by approximately $300 million, over the same period.
    - Subsequent to December 31, 2017, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes from funds flow from operations.
    - As at December 31, 2017, the Company's $3,000 million non-revolving term loan facility which it entered into during Q2/17 to finance the acquisition of AOSP and other assets was fully drawn. Subsequent to December 31, 2017, the Company repaid and canceled $150 million of the outstanding facility from funds flow from operations, leaving $2,850 million outstanding.
    - Subsequent to December 31, 2017, the Company fully repaid and canceled the $125 million non-revolving credit facility from funds flow from operations.

- Subsequent to December 31, 2017, the Company extended the $750 million non-revolving credit facility originally due February 2019 to February 2021.

- In addition to its strong funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at December 31, 2017, these financial levers include the Company’s third party equity investments of approximately $893 million.
- The Company remained focused on returns to shareholders in 2017 increasing dividends by approximately 17% to $1.10 per share. Subsequent to year end the Company increased its quarterly dividend by 22% to $0.335 per share payable on April 1, 2018. The increase marks the 18th consecutive year that Canadian Natural has increased its dividend, reflecting the Board of Director's confidence in the Company's sustainability and robustness of the asset base driving the ability to generate significant funds flow.

OUTLOOK

The Company forecasts annual 2018 production levels to average between 815,000 and 885,000 bbl/d of crude oil and NGLs and between 1,650 and 1,710 MMcf/d of natural gas, before royalties. Q1/18 production guidance before royalties is forecast to average between 821,000 and 869,000 bbl/d of crude oil and NGLs and between 1,600 and 1,650 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company’s website at www.cnrl.com.

Canadian Natural's annual 2018 capital expenditures are targeted to be approximately $4.3 billion.

2017 YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2017, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The IQREs conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

Corporate Total

- Canadian Natural's 2017 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding the change in Future Development Capital ("FDC"), are $5.15/BOE for proved reserves and $5.52/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $12.29/BOE for proved reserves and $12.17/BOE for proved plus probable reserves.
- Proved reserve additions and revisions replaced 2017 production by 927%. Proved plus probable reserve additions and revisions replaced 2017 production by 866%.
- Proved reserves increased 49% to 8.871 billion BOE with reserve additions and revisions of 3.253 billion BOE. Proved plus probable reserves increased 29% to 11.866 billion BOE with reserve additions and revisions of 3.038 billion BOE.
- The proved BOE reserve life index is 24.6 years and the proved plus probable BOE reserve life index is 33.0 years.
- Recycle ratios are 4.5 times and 4.2 times for proved and proved plus probable reserves respectively, excluding the change in FDC. Including the change in FDC, recycle ratios are 1.9 times for both proved and proved plus probable reserves.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 30% to $89.8 billion for proved reserves and increased 24% to $114.5 billion for proved plus probable reserves. The net present value for proved developed producing reserves increased 46% to $68.1 billion reflecting the completion of Horizon Phase 3 and the acquisition of AOSP.

North America Exploration and Production

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2017:
  - FD&A costs, excluding the change in FDC, are $6.81/BOE for proved reserves and $5.57/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $11.31/BOE for proved reserves and $9.96/BOE for proved plus probable reserves.
- Proved reserve additions and revisions replaced 196% of 2017 production. Proved plus probable reserve additions and revisions replaced 240% of 2017 production.
- Proved reserves increased 7% to 3.397 billion BOE. This is comprised of 2.275 billion bbl of crude oil, bitumen, and NGL reserves and 6.730 Tcf of natural gas reserves.
- Proved plus probable reserves increased 6% to 5.482 billion BOE. This is comprised of 3.895 billion bbl of crude oil, bitumen, and NGL reserves and 9.520 Tcf of natural gas reserves.
- Proved reserve additions and revisions are 320 million bbl of crude oil, bitumen and NGL and 770 Bcf of natural gas. Proved plus probable reserve additions and revisions are 349 million bbl of crude oil, bitumen and NGL and 1,194 Bcf of natural gas.
- The proved BOE reserve life index is 16.2 years and the proved plus probable BOE reserve life index is 26.2 years.

North America Oil Sands Mining and Upgrading

- Canadian Natural's Horizon and AOSP oil sands mining and upgrading delivered strong reserves results in 2017:
  - FD&A costs, excluding the change in FDC, are $4.78/bbl for proved reserves and $5.24/bbl for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $12.58/bbl for proved reserves and $12.78/bbl for proved plus probable reserves.
- Proved Synthetic Crude Oil ("SCO") reserves increased 106% to 5.264 billion bbl. Proved plus probable SCO reserves increased 68% to 6.063 billion bbl.
- SCO proved developed producing reserves increased 107% to 5.264 billion bbl reflecting the completion of Phase 3 at Horizon and the acquisition of AOSP.
- SCO reserves account for 59% of the Company's proved BOE reserves and 51% of the proved plus probable BOE reserves.

International Exploration and Production

- North Sea proved reserves decreased 12% to 124 million BOE and proved plus probable reserves decreased 31% to 185 million BOE.
- Offshore Africa proved reserves decreased 7% to 86 million BOE and proved plus probable reserves decreased 7% to 136 million BOE.

2017 FD&A Costs excluding change in FDC

	Proved ($/BOE)	Proved Plus Probable ($/BOE)
North America E&P	$ 6.81	$ 5.57
Oil Sands Mining and Upgrading	$ 4.78	$ 5.24
Total Canadian Natural	$ 5.15	$ 5.52

2017 FD&A Costs including change in FDC

	Proved ($/BOE)	Proved Plus Probable ($/BOE)
North America E&P	$ 11.31	$ 9.96
Oil Sands Mining and Upgrading	$ 12.58	$ 12.78
Total Canadian Natural	$ 12.29	$ 12.17

Corporate Total

2017 Reserve Replacement

Reserves Category	% of 2017 Production Replaced
Proved developed producing	887%
Proved	927%
Proved plus probable	866%

Company Gross Reserves

Reserves Category	2016 (MMBOE)	2017 (MMBOE)	Increase
Proved developed producing	4,145	6,908	67%
Proved	5,969	8,871	49%
Proved plus probable	9,179	11,866	29%

2017 Recycle Ratios

Reserves Category	Excluding change in FDC
Proved	4.5 x
Proved plus probable	4.2 x

Reserves Category	Including change in FDC
Proved	1.9 x
Proved plus probable	1.9 x

Net Present Value of Future Net Revenues, before income tax, discounted at 10%

Reserves Category	2016 ($ billion)	2017 ($ billion)	Increase
Proved developed producing	46.7	68.1	46%
Proved	69.3	89.8	30%
Proved plus probable	92.3	114.5	24%

Summary of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	108	266	322	5,264	4,029	102	6,848
Developed Non-Producing	11	15	—	34	—	347	8	126
Undeveloped	46	75	61	994	—	2,354	119	1,687
Total Proved	171	198	327	1,350	5,264	6,730	229	8,661
Probable	68	74	142	1,230	799	2,790	106	2,884
Total Proved plus Probable	239	272	469	2,580	6,063	9,520	335	11,545
North Sea								
Proved								
Developed Producing	25					17		28
Developed Non-Producing	4					—		4
Undeveloped	91					4		92
Total Proved	120					21		124
Probable	60					11		61
Total Proved plus Probable	180					32		185
Offshore Africa								
Proved								
Developed Producing	30					12		32
Developed Non-Producing	2					—		2
Undeveloped	51					8		52
Total Proved	83					20		86
Probable	42					47		50
Total Proved plus Probable	125					67		136
Total Company								
Proved								
Developed Producing	169	108	266	322	5,264	4,058	102	6,908
Developed Non-Producing	17	15	—	34	—	347	8	132
Undeveloped	188	75	61	994	—	2,366	119	1,831
Total Proved	374	198	327	1,350	5,264	6,771	229	8,871
Probable	170	74	142	1,230	799	2,848	106	2,995
Total Proved plus Probable	544	272	469	2,580	6,063	9,619	335	11,866

Summary of Company Net Reserves

As of December 31, 2017
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	103	91	207	262	4,552	3,654	80	5,904
Developed Non-Producing	10	13	—	28	—	312	6	109
Undeveloped	39	65	50	825	(9)	2,066	101	1,415
Total Proved	152	169	257	1,115	4,543	6,032	187	7,428
Probable	58	61	101	971	653	2,422	86	2,334
Total Proved plus Probable	210	230	358	2,086	5,196	8,454	273	9,762
North Sea								
Proved								
Developed Producing	25					17		28
Developed Non-Producing	4					—		4
Undeveloped	91					4		92
Total Proved	120					21		124
Probable	60					11		61
Total Proved plus Probable	180					32		185
Offshore Africa								
Proved								
Developed Producing	27					9		29
Developed Non-Producing	2					—		2
Undeveloped	41					6		42
Total Proved	70					15		73
Probable	32					32		37
Total Proved plus Probable	102					47		110
Total Company								
Proved								
Developed Producing	155	91	207	262	4,552	3,680	80	5,961
Developed Non-Producing	16	13	—	28	—	312	6	115
Undeveloped	171	65	50	825	(9)	2,076	101	1,549
Total Proved	342	169	257	1,115	4,543	6,068	187	7,625
Probable	150	61	101	971	653	2,465	86	2,432
Total Proved plus Probable	492	230	358	2,086	5,196	8,533	273	10,057

Reconciliation of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	168	187	264	1,269	2,559	6,545	198	5,736
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99
Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	(25)	—	(4)
Technical Revisions	7	4	5	82	487	211	13	633
Production	(18)	(35)	(19)	(44)	(103)	(585)	(15)	(332)
December 31, 2017	**171**	**198**	**327**	**1,350**	**5,264**	**6,730**	**229**	**8,661**

North Sea								
December 31, 2016	134					41		141
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	4					(5)		3
Technical Revisions	(9)					(1)		(9)
Production	(9)					(14)		(11)
December 31, 2017	**120**					**21**		**124**

Offshore Africa								
December 31, 2016	87					31		92
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	3					(3)		2
Production	(7)					(8)		(8)
December 31, 2017	**83**					**20**		**86**

Total Company								
December 31, 2016	389	187	264	1,269	2,559	6,617	198	5,969
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99
Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	4	—	—	—	—	(30)	—	(1)
Technical Revisions	1	4	5	82	487	207	13	626
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	**374**	**198**	**327**	**1,350**	**5,264**	**6,771**	**229**	**8,871**

Reconciliation of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	65	72	120	1,248	1,045	2,366	86	3,030
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	8	—	19	—	278	10	88
Infill Drilling	2	3	—	—	—	104	9	31
Improved Recovery	—	—	1	—	—	—	—	1
Acquisitions	2	6	23	27	175	29	—	237
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(4)	—	1
Technical Revisions	(6)	(15)	(2)	(64)	(421)	18	1	(504)
Production	—	—	—	—	—	—	—	—
December 31, 2017	**68**	**74**	**142**	**1,230**	**799**	**2,790**	**106**	**2,884**

North Sea

December 31, 2016	119	44	126
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	1	—	1
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	(4)	5	(3)
Technical Revisions	(56)	(38)	(63)
Production	—	—	—
December 31, 2017	**60**	**11**	**61**

Offshore Africa

December 31, 2016	46	49	54
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	(4)	(2)	(4)
Production	—	—	—
December 31, 2017	**42**	**47**	**50**

Total Company

December 31, 2016	230	72	120	1,248	1,045	2,459	86	3,210
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	8	—	19	—	278	10	88
Infill Drilling	3	3	—	—	—	104	9	32
Improved Recovery	—	—	1	—	—	—	—	1
Acquisitions	2	6	23	27	175	29	—	237
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	(3)	—	—	—	—	1	—	(2)
Technical Revisions	(66)	(15)	(2)	(64)	(421)	(22)	1	(571)
Production	—	—	—	—	—	—	—	—
December 31, 2017	**170**	**74**	**142**	**1,230**	**799**	**2,848**	**106**	**2,995**

Reconciliation of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	233	259	384	2,517	3,604	8,911	284	8,766
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	6	10	—	—	—	295	26	91
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	1	(11)	3	18	66	229	14	129
Production	(18)	(35)	(19)	(44)	(103)	(585)	(15)	(332)
December 31, 2017	**239**	**272**	**469**	**2,580**	**6,063**	**9,520**	**335**	**11,545**

North Sea

December 31, 2016	253					85		267
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(65)					(39)		(72)
Production	(9)					(14)		(11)
December 31, 2017	**180**					**32**		**185**

Offshore Africa

December 31, 2016	133					80		146
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(1)					(5)		(2)
Production	(7)					(8)		(8)
December 31, 2017	**125**					**67**		**136**

Total Company

December 31, 2016	619	259	384	2,517	3,604	9,076	284	9,179
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	7	10	—	—	—	295	26	92
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	(65)	(11)	3	18	66	185	14	55
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	**544**	**272**	**469**	**2,580**	**6,063**	**9,619**	**335**	**11,866**

Reserves Notes:

(1) *Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.*

(2) *Company Net reserves are working interest share after deduction of royalties and including any royalty interests.*

(3) *BOE values may not calculate due to rounding.*

(4) *Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:*

	2018	2019	2020	2021	2022	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 55.00	$ 65.00	$ 70.00	$ 73.00	$ 74.46	2.00%
Western Canada Select (C$/bbl)	$ 51.05	$ 59.61	$ 64.94	$ 68.43	$ 69.80	2.00%
Canadian Light Sweet (C$/bbl)	$ 65.44	$ 74.51	$ 78.24	$ 82.45	$ 84.10	2.00%
Cromer LSB (C$/bbl)	$ 64.44	$ 73.51	$ 77.24	$ 81.45	$ 83.10	2.00%
Edmonton Pentanes+ (C$/bbl)	$ 67.72	$ 75.61	$ 78.82	$ 82.35	$ 84.07	2.00%
North Sea Brent (US$/bbl)	$ 58.00	$ 67.00	$ 72.00	$ 75.00	$ 76.50	2.00%
Natural gas						
AECO (C$/MMBtu)	$ 2.85	$ 3.11	$ 3.65	$ 3.80	$ 3.95	2.00%
BC Westcoast Station 2 (C$/MMBtu)	$ 2.45	$ 2.71	$ 3.25	$ 3.40	$ 3.55	2.00%
Henry Hub (US$/MMBtu)	$ 3.25	$ 3.50	$ 4.00	$ 4.08	$ 4.16	2.00%

Note: A foreign exchange rate of 0.7900 US$/C$ for 2018, 0.8200 US$/C$ for 2019, and 0.8500 US$/C$ after 2019 was used in the 2017 evaluation.

(5) *A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.*

(6) *Metrics included herein are commonly used in the oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.*

(7) *Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.*

(8) *Reserve replacement or Production replacement ratio is the Company Gross reserve additions and revisions, for the relevant reserve category, divided by the Company Gross production in the same period.*

(9) *Reserve Life Index is based on the amount for the relevant reserve category divided by the 2018 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.*

(10) *Finding, Development and Acquisition ("FD&A") costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2017 by the sum of total additions and revisions for the relevant reserve category.*

(11) *FD&A costs including change in Future Development Capital ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2017 and net change in FDC from December 31, 2016 to December 31, 2017 by the sum of total additions and revisions for the relevant reserve category. FDC excludes all abandonment and reclamation costs.*

(12) *Recycle Ratio is the operating netback ($23.40/BOE for 2017) divided by the FD&A (in $/BOE). Operating netback is production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and production expenses, calculated on a per BOE basis.*

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout the Company's Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost of construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets, including the interests in AOSP as well as additional working interests in certain other producing and non-producing oil and gas properties (the "other assets"), acquired by the Company on May 31, 2017; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company’s operations have been, and in the future may be, affected by political developments and by national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.

Special Note Regarding Currency, Production and Non-GAPP Financial Measures

The Company's MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2017 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended December 31, 2017 and the Company's MD&A have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board. The Company's MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, funds flow from operations (previously referred to as cash flow from operations), and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the “Financial Highlights” section of the Company's MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the “Operating Highlights - Oil Sands Mining and Upgrading” section of the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of the Company's MD&A.

A Barrel of Oil Equivalent (“BOE”) is derived by converting six thousand cubic feet (“Mcf”) of natural gas to one barrel (“bbl”) of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of the Company's MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO.

Production volumes and per unit statistics are presented throughout the Company's MD&A on a “before royalty” or “gross” basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. Production on an “after royalty” or “net” basis is also presented for information purposes only.

Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, March 1, 2018.

The North American conference call number is 1-866-521-4909 and the outside North American conference call number is 001-647-427-2311. Please call in 10 minutes prior to the call starting time.

An archive of the broadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 15, 2018. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference archive ID number is 9424719.

The conference call will also be webcast live and may be accessed on the home page of our website at www.cnrl.com.

For further information, please contact:

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Director, Treasury and Investor Relations

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